GAO Statement of Facts

Review of Federal and State Regulatory Framework for Unconventional Oil and Gas Development

Job Code 361347

Environmental Protection Agency

Objectives of the Review:

GAO was asked to review environmental and public health requirements for oil and gas development from onshore unconventional reservoirs. For such development, this report

(1) describes federal environmental and public health requirements;

(2) describes state requirements;

(3) describes additional requirements that apply on federal lands; and

(4) identifies challenges, if any, that federal and state agencies reported facing in regulating oil and gas development from unconventional reservoirs.

Background

- The Environmental Protection Agency (EPA) administers and enforces key federal laws, such as the Safe Drinking Water Act, that aim to protect human health and the environment, and EPA regional offices work with states which implement some aspects of these laws as well as additional state requirements. EPA is also conducting a study, as directed by a congressional committee, to examine the potential effects of hydraulic fracturing on drinking water resources.[1]

Activities Associated With Oil and Gas Development

- Developing unconventional reservoirs involves a variety of activities, many of which are also conducted in conventional oil and gas drilling, including:
- *Siting and site preparation*. The operator identifies a location for the well and prepares the area of land where drilling will take place—referred to as a well pad. In some cases, the operator will build new access roads to transport equipment to the well pad or install new pipelines to transport the oil or gas that is produced. In addition, the operator will clear vegetation from the area and may place storage tanks (also called vessels) or construct pits on the well pad for temporarily storing fluids. In some cases, multiple wells will be located on a single well pad.
- *Drilling, casing, and cementing*. The operator conducts several phases of drilling to install multiple layers of steel pipe—called casing—and cement the casing in place. The layers of steel casing are intended to isolate the internal portion of the well from the outlying geological formations, which may include underground sources of drinking water. As the well is drilled deeper, progressively narrower casing is inserted further down the well and cemented in place. Throughout the drilling process, special lubricant called drilling fluid is circulated down the well to lubricate the drilling assembly and carry drill cuttings (essentially rock fragments created during drilling) back to the surface. After vertical drilling is complete, horizontal drilling is conducted by slowly angling the drill bit until it is drilling horizontally. In shale, tight sandstone, and some coalbed methane formations, production casing is installed in the horizontal portion of the well. Horizontal stretches of the well typically range from 2,000 feet to 6,000 feet long, but can be as long as 12,000 feet in some cases.
- *Hydraulic fracturing*. Hydraulic fracturing involves sequentially pumping a fluid mixture down the well and into the target formation at high enough pressures to cause the rock within the

[1]EPA's Office of Research and Development began this study in January 2010 to examine the potential effects of hydraulic fracturing on drinking water resources. The agency anticipates issuing an interim report in the fall of 2012 and a final report in 2014.

target formation to fracture. About 98 percent of the fluid mixture is water and sequential fracturing of a well can use between 3 million and 5.6 million gallons.[2] A proppant, such as sand, is added to the mixture to keep the fractures open despite the large pressure of the overlying rock. In addition, the fluid mixture—or hydraulic fracturing fluid—generally contains a number of chemical additives, each of which is designed to serve a particular purpose. For example, operators may use a friction reducer to minimize friction between the fluid and the pipe, acid to help dissolve minerals and initiate cracks in the rock, and a biocide to eliminate bacteria in the water that cause corrosion. The number of chemicals used and their concentrations depend upon the particular conditions of the well. After hydraulic fracturing, a mixture of fluids and gases flow back to the surface,[3] after which production can begin and the well is said to have been completed. Hydraulic fracturing is used in many shale and tight sandstone formations (see fig. A). Some coalbed methane wells are hydraulically fractured (see fig. B), but companies may use different combinations of water, sand, and chemicals than with other unconventional wells. In addition, operators must "dewater" coalbed methane formations in order to get the natural gas to begin flowing—a process that can take several months and generate large amounts of water.[4]

[2]In acquiring this water, operators are required to follow state, regional water authority, and local laws regarding water withdrawals, but these are outside the scope of this report

[3]Not all the fluids injected into the well during hydraulic fracturing necessarily flow back to the surface.

[4]The water pressure within coalbed methane formations forces natural gas to adhere to the coal. Capturing the gas requires operators to pump water out of the coal formation to reduce the pressure, allowing the natural gas to release (desorb) from the surface of the coal, diffuse through micropores, and then flow through coal cleats (natural fracture networks) into the well.

Figure A. Horizontal Drilling and Hydraulic Fracturing in an Unconventional Shale Formation

Figure B. Hydraulic Fracturing in a Coalbed Methane Formation

removing equipment from the well pad, closing pits, backfilling soil, and restoring vegetation.[5] Sometimes, when a well starts production, operators reclaim the portions of a site affected by the initial drilling activity.

- *Waste management and disposal*. Throughout the drilling, hydraulic fracturing, and subsequent production activities, operators must manage and dispose of several types of waste. For example, operators must manage produced water, which includes flowback water—the water, proppant, and chemicals used for hydraulic fracturing—as well as water that occurs naturally in the oil- or gas-bearing geological formation. Operators temporarily store produced water in tanks or pits, and some operators may recycle it for re-use in subsequent hydraulic fracturing. Options for permanently disposing of produced water vary and may include, for example, injecting it underground into wells designated for such purposes. Operators also generate solid wastes such as drill cuttings, and could potentially generate small quantities of hazardous waste. See table 1 for additional methods for managing and disposing of waste.

Table 1. Potential Waste Management and Disposal Options

	Liquid waste	Solid waste	Hazardous waste
Primary types of waste	Produced water	Drill cuttings Drilling mud Trash	Unused hydraulic fracturing chemicals Tank bottom waste Certain other chemical and oily wastes
Options for Temporary storage	Tanks or pits	Tanks or pits	Tanks
Options for Reuse	Recycle Landspreading (used for agriculture irrigation) Roadspreading (used for dust or ice suppression)	Roadspreading of drill cuttings Reuse of drilling mud	N/A
Options for Permanent disposal	Underground injection well Discharge to surface water Commercial treatment facilities Publicly-owned treatment works	Solid waste landfill Bury drill cuttings on well pad	Hazardous waste disposal facility

Source: GAO.
Note: This table identifies a range of temporary storage and permanent disposal options. Depending on the region or state, some practices may not be technically feasible or legally permissible. The table lists potential disposal options; in some cases, treatment would be typical or required before disposal.

[5]Backfilling is refilling a pit or other area with soil.

- *Managing air emissions*. Throughout the drilling, hydraulic fracturing, and production activities, operators also are to manage air emissions. There are four key types of air emissions that may occur at oil and gas well sites:
    - Criteria pollutants are a set of common air pollutants that include ground level ozone, nitrogen oxides, particulate matter, and carbon monoxide.[6] Ground level ozone is created by chemical reactions between nitrogen oxides and volatile organic compounds and can cause health effects such as chest pain, coughing, throat irritation, and congestion. Nitrogen oxides have been linked to respiratory illness and acid rain. Particulate matter is a complex mixture of extremely small particles and liquid droplets, some of which can affect the heart and lungs and cause serious health effects. Carbon monoxide can cause harmful health effects by reducing oxygen delivery to the body's organs (like the heart and brain).
    - Hazardous air pollutants, such as benzene, are pollutants known or suspected to cause cancer or other serious health effects or adverse environmental effects.
    - Hydrogen sulfide is a toxic, flammable, and odorless gas that poses a particular safety danger to workers at the well site.
    - Methane is a greenhouse gas that, according to some estimates, is over 20 times more efficient in trapping heat in the atmosphere than carbon dioxide over a 100-year period.
- Emissions related to oil and gas production are from both stationary sources and mobile sources (see fig. C). Stationary sources include wells, pumps, storage vessels, pneumatic controllers, dehydrators, pits, and flaring.[7] Mobile sources include trucks bringing fuel, water, or supplies to the well site; construction vehicles; and truck-mounted pumps or engines used for drilling or hydraulic fracturing.

[6]The other criteria pollutants are sulfur dioxide and lead, but these are not commonly associated with oil and gas development.
[7]Flaring involves the burning of gas either for safety reasons or because operators do not have the infrastructure to bring the gas to market.

Figure C. Potential Sources and Types of Air Emissions from Oil and Gas Production

- Toxic Substances Control Act (TSCA)
- Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA).

In large part, the same requirements apply to conventional and unconventional oil and gas development.

Safe Drinking Water Act

- SDWA is the main federal law that ensures the quality of drinking water.[8] Two key aspects of SDWA that are part of the regulatory framework governing unconventional oil and gas development are the Underground Injection Control (UIC) program and the imminent and substantial endangerment provision.

Underground Injection Control Program

- Under the SDWA, EPA regulates the injection of fluids underground through its Underground Injection Control (UIC) program, including the injection of produced water from oil and gas development. The UIC program protects underground sources of drinking water by setting and enforcing standards for siting, constructing, and operating injection wells. Injection wells in the UIC program fall into six different categories based on the types of waste being injected. The wells used to manage fluids associated with oil and gas production, including produced water, are Class II wells.[9]
- EPA documents estimate there are approximately 144,000 Class II UIC wells in operation in the United States. Two types of wells account for nearly all the Class II UIC wells in the United States (see fig. D):
- Enhanced recovery wells inject produced water or other fluids into oil-producing formations to increase the pressure in the formation and force additional oil out of nearby producing wells. EPA documents estimate that about 80 percent of Class II wells are enhanced recovery wells.
- Disposal wells inject produced water or other fluids associated with oil and gas production into formations that will hold the fluids indefinitely. EPA documents estimate that about 20 percent of Class II wells are disposal wells.[10]

[8]Pub. L. No. 93-523 (1974), codified as amended at 42 U.S.C. §§ 300f–300j-26 (2010).
[9]Other classes of UIC wells are used by other industries. For example, Class I wells are for the injection of hazardous, radioactive, and industrial wastes. Class III wells are used for the injection of fluids as part of mining operations, such as for mining salts or uranium.
[10]A third type of Class II UIC well is a hydrocarbon storage well, which injects liquid hydrocarbons into underground formations, such as salt caverns, which can store the hydrocarbons for later use. EPA estimates there are over 100 hydrocarbon storage wells in use in the United States.

Figure D. Enhanced Recovery and Disposal Wells

responsibility for executing its program, including permitting and monitoring UIC wells. To be approved for primacy, state programs must be at least as stringent as the federal program for each of the well classes for which primacy is sought. SDWA also includes alternative provisions for primacy related to Class II wells whereby, in lieu of adopting all EPA Class II UIC requirements, a state can demonstrate to EPA that its program is effective in preventing endangerment of underground sources of drinking water. Five of the six states in our review (Colorado, North Dakota, Ohio, Texas, and Wyoming) have been granted primacy for Class II wells under the alternative provisions. Pennsylvania has few Class II UIC wells and has not applied for primacy, so EPA directly implements the program there.

- As discussed, the UIC program regulates the injection of fluids underground. Historically, the UIC program has only been used to regulate injection wells (such as enhanced recovery wells or disposal wells) and was not used to regulate hydraulic fracturing, even though fracturing also entails the injection of fluid underground. In 1994, in light of concerns that hydraulic fracturing of coalbed methane wells threatened drinking water, citizens petitioned EPA to withdraw its approval of Alabama's Class II UIC program because it failed to regulate hydraulic fracturing. The case ended up before the U.S. Court of Appeals for the 11th Circuit, which held that the definition of underground injection included hydraulic fracturing. The Court's decision was made in the context of hydraulic fracturing of a coalbed methane formation in Alabama, but it raised questions about whether hydraulic fracturing would be included in UIC programs nationwide.[11]
- In 2005, the Energy Policy Act added a provision to SDWA specifically exempting hydraulic fracturing from the UIC program, except if diesel fuel is injected as part of hydraulic fracturing. The 2005 Act allowed hydraulic fracturing using diesel to be regulated under the UIC program, but did not mandate that EPA take any actions.[12] EPA officials told us that they do not have data about how frequently companies currently use diesel in hydraulic fracturing.[13] Since 2005, EPA officials said that EPA has not received any permit applications nor issued any permits authorizing diesel to be used in hydraulic fracturing. EPA officials also said that they were not aware of any state UIC programs that had issued

[11]The court ordered EPA to reconsider its approval of Alabama's program. Legal Environmental Assistance Foundation v. EPA, 118 F.3d 1467, 1471 (11th Cir.1997).
[12]UIC regulations at the time and now provide that "[a]ny underground injection, except into a well authorized by rule or except as authorized by permit issued under the UIC program, is prohibited." 40 C.F.R. 144.11 (2005) (2011). The Energy Policy Act provision did not exempt injections of diesel fuel during hydraulic fracturing from the definition of underground injection.
[13]In 2003, EPA entered into a Memorandum of Agreement with three major fracturing service companies in which the companies voluntarily agreed to eliminate diesel fuel in hydraulic fracturing fluids injected into coalbed methane production wells in underground sources of drinking water.

such permits. EPA recently developed draft guidance on how EPA UIC permit writers should address hydraulic fracturing with diesel in the context of the Class II UIC program in states where EPA directly implements the program; the guidance does not apply to state-run UIC programs. EPA's draft guidance is applicable to any oil and gas wells using diesel in hydraulic fracturing (not just coalbed methane wells). The draft guidance provides recommendations related to permit applications, area of review (for other nearby wells), well construction, permit duration, and well closure.

Imminent and Substantial Endangerment Authority

- In addition to responsibilities under the UIC program, SDWA gives EPA authority to issue orders when EPA receives information about present or likely contamination of a public water system or an underground source of drinking water that may present an imminent and substantial endangerment to human health. In December 2010, EPA used this authority to issue an emergency administrative order to the Range Resources Corporation alleging that the company's oil and gas production facilities near Fort Worth, Texas, were related to methane contamination in two nearby private drinking water wells. EPA contended that this methane contamination posed an explosion hazard and therefore was an imminent and substantial threat to human health. EPA's order required Range Resources to take six actions, specifically: (1) notify EPA whether it intended to comply with the order; (2) provide replacement water supplies to landowners; (3) install meters to monitor for the risk of explosion at the affected homes; (4) conduct a survey of any additional private water wells within 3,000 feet of the oil and gas production facilities, (5) develop a plan to conduct soil and indoor air monitoring at the affected dwellings, and (6) develop a plan to investigate how methane flowed into the aquifer and private drinking water wells. Range Resources disputed the validity of EPA's order and noted that the order does not provide any way for the company to challenge EPA's findings. Nevertheless, Range Resources implemented the first three actions EPA listed in the order. In January 2011, EPA sued Range Resources in District Court, seeking to enforce the remaining three provisions of the order. In March 2011, the regulatory agency that oversees oil and gas development in Texas held a hearing examining Range Resources' possible role in the contamination of the water wells and issued an order in which it concluded that Range Resources had not caused the contamination. In March 2012, EPA withdrew the original emergency administrative order, and Range Resources agreed to continue monitoring 20 private water wells near its production sites for 1 year. According to EPA officials, resolving the lawsuit allows the agency to shift its focus away from litigation and toward the joint effort in monitoring.

Clean Water Act

- CWA is the main federal law that regulates discharges of pollutants into surface waters, such as rivers and streams.[14] Under CWA, EPA regulates discharges of pollutants to surface waters of the United States. Several aspects of CWA are applicable to oil and gas well pad sites, but exemptions from certain requirements diminish EPA's oversight role. Relevant parts of CWA include the National Pollutant Discharge Elimination System (NPDES) program for discharges from industrial sites and stormwater discharges; spill reporting and spill prevention and response planning requirements; and EPA's response authority, under which EPA can bring suit or take other actions to protect the public health and welfare from actual or threatened discharges of oil or hazardous substances to surface waters.

NPDES

- EPA's NPDES program limits the types and amounts of pollutants that industrial sites, industrial wastewater treatment facilities, and municipal wastewater treatment facilities (often called publicly-owned treatment works or POTWs) can discharge into the nation's surface waters by requiring these facilities to have and comply with permits listing the allowable discharge for each pollutant. As required by CWA, EPA develops effluent limitations for certain industrial categories based on available control technologies and other factors to prevent or treat the discharge. EPA established multiple subcategories within the oil and gas industry, including: (1) onshore, (2) agricultural and wildlife water use, and (3) stripper wells—that is, wells that produce relatively small amounts of oil or gas.[15] For the onshore and agricultural and wildlife water use subcategories, EPA established effluent limitation guidelines for direct dischargers that establish minimum requirements to be used by EPA and state NPDES permit writers. Specifically, the onshore subcategory has a zero discharge limit for discharges to surface waters, meaning that no direct discharges to surface waters are allowed. EPA documents explain that this is because there are technologies available—such as underground injection—to dispose of produced water generated at oil and gas well sites without directly discharging them to surface waters. Given that the NPDES permit limit would be "no discharge," EPA officials said that they were unaware of any instances in which operators had applied for these permits. EPA officials did mention, however, instances in which operators discharged produced water to streams and were fined by EPA

[14] The Federal Water Pollution Control Act Amendments of 1972, Pub. L. No. 92-500, § 2, 86 Stat. 816 codified as amended at 33 U.S.C. §§ 1251-1387 (2011) (commonly referred to as the Clean Water Act).
[15] EPA established additional industrial categories in the oil and gas sector for wells in certain near-shore coastal areas, but effluent limitation guidelines for this category are not discussed here, as this report is focused on onshore unconventional oil and gas production.

under provisions in CWA. For example, in 2011, EPA Region 6 assessed an administrative civil penalty against a company managing two oil production facilities in Oklahoma for discharging brine and produced water to a nearby stream. The company ultimately agreed to pay a $1,500 fine and conduct an environmental project, which included extensive soil remediation near the facilities. Effluent limitation guidelines for the agricultural and wildlife water use subcategory cover a geographical subset of wells in the west[16] in which the quality of produced water from the wells is of good enough quality for watering crops and livestock or to support wildlife in streams. The effluent limitation guideline for this subcategory allows such discharges of produced water for these purposes as long as the water meets a minimum quality standard for oil and grease.

- EPA did not establish guidelines for stripper wells or coalbed methane wells and, according to EPA officials, EPA and state NPDES permit writers currently use their best professional judgment to determine the effluent limits for permits on a case-by-case basis. Regarding stripper wells, EPA explained in a 1976 *Federal Register* notice that unacceptable economic impacts would occur and that the agency could revisit this decision at a later date. EPA officials confirmed that the agency currently has no plans to develop an effluent limitation guideline for stripper wells. Regarding coalbed methane wells, EPA officials explained that the process of extracting natural gas from coalbed methane formations is fundamentally different from traditional oil and gas development, partly because of the large volume of water must be removed from the coalbed methane formation prior to production. Given these differences, coalbed methane wells are not included in any of EPA's current subcategories. EPA announced in 2010 that, based on a multi-year study of the coalbed methane industry, the agency will develop effluent limitation guidelines for produced water discharges from coalbed methane formations. In the course of developing these guidelines, EPA officials said they will analyze the economic feasibility of each of the available technologies for disposing of the large volumes of produced water from coalbed methane wells and that EPA plans to issue proposed guidelines in the summer of 2013.
- In addition to setting effluent limitation guidelines for direct discharges of pollutants to surface waters, EPA sets pretreatment standards that apply when wastewater is sent to a facility—such as an industrial treatment facility or POTW—before being discharged to surface waters. To date, EPA has not set pretreatment standards specifically for produced water, though there are some general requirements; for example, discharges to POTWs

[16]Specifically, the agricultural and wildlife water use subcategory includes wells located west of the 98th meridian, which extends from approximately the eastern border of North Dakota south through central Texas.

cannot cause the POTW to violate its NPDES permit or interfere with the treatment process. In October 2011, EPA announced its intention to develop pretreatment standards specific to the produced water from shale gas development. EPA officials told us that the agency intends to conduct a survey and use other methods to collect additional data and information to support this rulemaking. Officials expect to publish the first *Federal Register* notice about the survey by the end of 2012 and to publish a proposed rule in the fall of 2014.[17]

- In addition to requiring NPDES permits for discharges from industrial sites, the 1987 Water Quality Act amended CWA to establish a specific program for regulating stormwater discharges, such as those caused by rainstorms, though oil and gas well sites are largely exempt from these requirements. EPA generally requires that facilities get NPDES permits for discharges of stormwater associated with industrial and construction activities, but the Water Quality Act of 1987 specifically exempted oil and gas production sites from permit requirements for stormwater discharges, as long as the stormwater was not contaminated by, for example, industrial materials or waste products. As a result of this exemption and EPA's implementing regulations, oil and gas well sites are required to get NPDES permits for stormwater only if the stormwater is contaminated by a reportable quantity of a pollutant or contributes to the violation of a water quality standard.[18] The 2005 Energy Policy Act expanded the language of the exemption to include construction activities at oil and gas well sites, meaning that uncontaminated stormwater discharges from oil and gas construction sites also do not require NPDES permits. So while other industries must obtain NPDES permits for construction activities, operators of oil and gas well sites are not required to do so.

Spill Reporting and Spill Prevention and Response Planning

- CWA prohibits discharges of oil or hazardous substances into surface waters. Specifically, CWA requires facilities—including oil and gas well sites—to report any unpermitted releases of oil or hazardous substances above threshold quantities to the National Response Center, which is an interagency center managed by the U.S. Coast Guard that serves as the sole federal point of contact for reporting oil and chemical spills in the United States. Oil discharges must be reported if they cause a film or sheen on the surface of the water or shorelines or if they violate water quality standards. The National Response Center shares

[17]POTWs will be discussed in greater detail later in this report.
[18]EPA has established by regulation threshold amounts of certain pollutants that if released trigger reporting requirements; these amounts are known as "reportable quantities." Specifically, the reportable quantities triggering a permit are listed in 40 C.F.R. §§ 117.21, 302.6, 110.6 (2011).

information about spills with other agencies, including EPA regional offices, which allows EPA to follow up on reported spills, as appropriate.

- CWA also established spill prevention and response planning requirements as described in the Spill Prevention, Control, and Countermeasure (SPCC) rule of 2002. Facilities that are subject to SPCC rules are required to prepare and implement a plan describing, among other things, how they will control, contain, clean up, and mitigate the effects of any oil discharges that occur. Onshore oil and gas well sites, among others, are subject to this rule if they have total aboveground oil storage capacity greater than 1,320 gallons and could reasonably be expected, based on location, to discharge oil into surface waters. The amount of oil storage capacity at oil and gas well sites tends to vary based on whether the well is being drilled, hydraulically fractured, or has entered production. For example, during drilling at well sites located near surface waters, operators have to comply with SPCC requirements if fuel tanks for the drilling rig exceed the 1,320 gallon threshold. According to EPA officials, nearly all drill rigs have fuel tanks larger than 1,320 gallons and so most well sites are subject to the SPCC rule during drilling if they are near surface waters.
- In accordance with CWA, EPA directly administers the SPCC program rather than delegating authority to states. EPA regulations do not require facilities to report information to EPA, including whether or not they are regulated. As a result, EPA does not know the universe of SPCC-regulated facilities.[19] To ensure that regulated facilities are meeting SPCC requirements, EPA regional personnel may inspect these facilities to evaluate their compliance. EPA officials said that some of these inspections were conducted as follow-up after spills were reported and that most inspections are conducted during the production phase, since drilling and hydraulic fracturing are of much shorter durations, making it difficult for inspectors to visit these sites during those times. According to EPA officials, regional personnel inspected 120 oil and gas well sites in fiscal year 2011 and found noncompliance at 105 of these sites ranging from paperwork inconsistencies at X sites to more serious violations such as XYZ at Y sites. EPA officials said that EPA has not taken any enforcement actions in cases related to any of these violations because ABC. According to a 2003 report by EPA region 8, EPA region 8 issued notices of violation related to

[19]See GAO, *Aboveground Oil Storage Tanks: More Complete Facility Data Could Improve Implementation of EPA's Spill Prevention Program*, GAO-08-482 (Washington, D.C.: Apr. 30, 2008). In that report, we found that EPA has information on only a portion of the facilities subject to the SPCC rule, hindering its ability to identify and effectively target facilities for inspection and enforcement. We recommended that EPA analyze the costs and benefits of the options available to EPA for obtaining key data about the universe of SPCC-regulated facilities, including, among others, a tank registration program similar to those employed by some states. EPA has begun taking action on this recommendation.

noncompliance of oil and gas well sites with SPCC regulations that were found between 1996 and 2002.[20] These notices of violation provide information to operators about a violation and give the operator an adequate period of time to correct them. The report notes that many operators came into compliance after receiving the notice of violation but that formal EPA action was taken in some cases.

Imminent and Substantial Endangerment and Release Response Authorities

- The CWA also provides EPA with authorities to address the discharge of pollutants and to address actual or threatened discharges of oil or hazardous substances in certain circumstances. For example, EPA has the authority to address releases of oil or hazardous substances to surface waters upon a determination that there may be an imminent and substantial threat to the public health or welfare of the United States, by bringing suit or taking other action, including issuing administrative orders that may be necessary to protect public health and welfare. EPA also has authority to obtain records and access to facilities, among other things, in order to determine if a person is violating certain CWA requirements. For example, EPA conducted initial investigations in Bradford County, Pennsylvania following a 2011 spill of hydraulic fracturing and other fluids that entered a stream. Citing its authority under the CWA and other laws,[21] EPA requested information from the operator about the incident, including information about the chemicals involved and the environmental effects of the spill. EPA coordinated with the Pennsylvania Department of Environmental Protection, which ultimately took the lead in the case and signed a consent agreement with the operator in 2012 that required the operator to pay fines and implement a monitoring plan for the affected stream.

Clean Air Act

- CAA, a federal law that regulates air pollution from mobile and stationary sources, was enacted to improve and protect the quality of the nation's air.[22] Under CAA, EPA sets national ambient air quality standards for the six criteria pollutants—ground level ozone, carbon monoxide, particulate matter, sulfur oxides, nitrogen dioxide, and lead—at levels it determines are necessary to protect public health and welfare. States then develop state implementation plans (SIP) to establish how the state will attain air quality standards, through regulation, permits, policies, and other means. States must obtain EPA approval for SIPs; if a SIP is not acceptable, EPA may assume responsibility for implementing and

[20]EPA Region 8, *Report of the United States Environmental Protection Agency Region 8 Oil and Gas Environmental Assessment Effort 1996 – 2002* (Denver, CO: January 2003).
[21]Specifically, EPA cited authorities under CWA section 308, as well as under CERCLA and RCRA.
[22]Clean Air Act Amendments of 1970, Pub. L. No. 91-604, 84 Stat. 1676 (1970), codified as amended at 42 U.S.C. §§ 7401-7671q (2011) (commonly referred to as the Clean Air Act).

enforcing CAA in that state. CAA also authorizes EPA to regulate emissions of hazardous air pollutants, such as benzene. In addition, under the CAA, EPA requires reporting of greenhouse gas emissions from a variety of sources, including oil and gas wells.

Mobile Sources – Criteria Air Pollutants

- In accordance with CAA, EPA has progressively implemented more stringent diesel emissions standards to lower the amount of key pollutants from mobile diesel-powered engines since 1984.[23] These standards apply to a variety of on- and off-road diesel powered engines, including trucks used in the oil and gas industry to move materials to and from well sites and compressors used to drill and hydraulically fracture wells. Diesel exhaust contains nitrogen oxides, particulate matter, and carbon monoxide. Emissions standards may set limits on the amount of pollution a vehicle or engine can emit or establish requirements about how the vehicle or engine must be maintained or operated, and generally apply to new vehicles. For example, the most recent emissions standards for construction equipment began to take effect in 2008 and required a 95 percent reduction in nitrogen oxides and a 90 percent reduction in particulate matter from previous standards, which took effect in 2006 and 2007. EPA estimates that millions of older mobile sources—including on-road and off-road engines and vehicles—remain in use. It is projected that over time, older sources will be taken out of use and be replaced by the lower-emission vehicles, ultimately reducing emissions from mobile sources.

Stationary Sources – Criteria Air Pollutants

- New Source Performance Standards (NSPS) apply to new stationary facilities or modifications to stationary facilities that result in increases in air emissions and focus on criteria air pollutants or their precursors. For the oil and gas industry, the key pollutant is volatile organic compounds, which are a precursor to ground-level ozone formation. Prior to 2012, EPA's NSPS were unlikely to affect oil and gas well sites because (1) EPA had not promulgated standards directly targeting well sites[24] and (2) to the extent that EPA promulgated standards for equipment that may be located at well sites, the capacity of equipment located at well sites was generally too low to trigger the requirement. For example, in 1987, EPA issued a NSPS for storage vessels containing petroleum liquids; however the standards apply only to tanks above a certain size, and EPA officials said that most storage tanks at oil and gas sites are below the threshold.

[23] See GAO, *Diesel Pollution: Fragmented Federal Programs That Reduce Mobile Source Emissions Could Be Improved*, GAO-12-261 (Washington, D.C.: Feb. 7, 2012).

[24] EPA did promulgate standards related to other parts of the oil and gas industry. For example, in 1985, EPA promulgated NSPS that focused on natural gas processing plants, which remove impurities from natural gas to prepare it for use by consumers.

- In April 2012, EPA promulgated a NSPS for the oil and natural gas production industry that, when fully phased-in by 2015, will require emissions reductions at oil and gas well sites, including wells using hydraulic fracturing.[25] Specifically, these new standards are related to pneumatic controllers, well completions, and certain storage vessels as follows:
    - *Pneumatic controllers.* According to EPA, when pneumatic controllers are powered by natural gas, they may release natural gas and volatile organic compounds during normal operations. The new standard sets limits for the amount of gas new and modified pneumatic controllers can release per hour. EPA's regulatory impact analysis for the NSPS estimates that about 13,600 new or modified pneumatic controllers will be required to meet the standard annually; EPA also estimates that the oil and gas production sector currently uses about 400,000 pneumatic controllers.
    - *Well completions for hydraulically fractured natural gas wells*. EPA's NSPS for well completion focus on reducing the venting of natural gas and volatile organic compounds during flowback after hydraulic fracturing. According to EPA's regulatory impact analysis, natural gas well completions involving hydraulic fracturing vent approximately 230 times more natural gas and volatile organic compounds than natural gas well completions that do not involve hydraulic fracturing. The regulatory impact analysis attributes these emissions to the practice of routing flowback of fracture fluids and reservoir gas to a surface impoundment (pit) where natural gas and volatile organic compounds escape to the atmosphere. To reduce the release of natural gas and volatile organic compounds from hydraulically fractured natural gas wells, EPA's new rule will require operators to use "green completion" techniques to capture and treat natural gas so that it can be sold or otherwise used. EPA's regulatory impact analysis for the rule estimates that more than 9,400 wells will be required to meet the new standard annually.[26]
    - *Storage vessels*. Storage vessels are used at well sites (and in other parts of the oil and gas industry) to store crude oil, oil condensate, and produced water. These vessels emit gas and volatile organic compounds when they are being filled or emptied and in association with changes of temperature. EPA's NSPS

[25]EPA's April 2012 rulemaking also set NSPS for other parts of the oil and natural gas industry, including for equipment leaks, certain types of compressors, and pneumatic controllers located at natural gas processing plants.
[26]This estimate includes green completions that are required to occur under the rule, including some that would likely occur voluntarily (e.g., without the rule). EPA estimated that of this total approximately 4,600 would likely occur voluntarily.

rule will require storage vessels that emit more than 6 tons per year of volatile organic compounds to reduce these emissions by at least 95 percent. EPA's regulatory impact analysis for the rule estimates that approximately 300 storage vessels used by the oil and gas industry will be required to meet the new standard annually, but it is unclear to what extent these storage vessels are located at well sites.

Stationary Sources – Hazardous Air Pollutants

- EPA also regulates hazardous air pollutants emitted by stationary sources. In accordance with the 1990 amendments to CAA, EPA does this by identifying categories of industrial sources of hazardous air pollutants and requiring those sources to reduce emissions by installing controls or changing production practices. These National Emission Standards for Hazardous Air Pollutants (NESHAP) for each industrial source category include standards for major sources, which are defined as sources with the potential to emit more than 10 tons per year of a hazardous air pollutant or more than 25 tons per year of a combination of pollutants, as well as for area sources, which are sources of hazardous air pollutants that are not defined as major sources. Generally, EPA or state regulators can aggregate emissions from related or nearby equipment to determine whether the unit or facility should be regulated as a major source. However, CAA expressly prohibits aggregating emissions from oil and gas wells with emissions from other equipment, such as pipeline compressors or pumping stations, to determine whether the oil or gas well is a major source of hazardous air pollutants.
- EPA initially promulgated a NESHAP for oil and natural gas production facilities for major sources in 1999 and promulgated amendments in April 2012. NESHAPs generally identify emissions points that may be present at facilities within each industrial source category. The source category for oil and natural gas production facilities includes oil and gas well sites and other oil and gas facilities, such as pipeline gathering stations and natural gas processing plants. As such, the NESHAP for the oil and natural gas production facilities category includes emissions points that may be present at natural gas processing plants but would not normally be found at well sites. EPA officials in each of the four regions we contacted were unaware of any examples of oil and natural gas wells being regulated as major sources of hazardous air pollutants before the April 2012 amendments. These amendments, however, changed a key definition used to determine whether a facility (such as a well site) is a major source. Under the new definition, emissions from all storage vessels and glycol dehydrators (used to remove water from gas being produced) at a facility

will be counted toward determining whether a facility is a major source. EPA's regulatory impact analysis and other technical support documents for the April 2012 amendments did not estimate how many oil and natural gas well sites would be considered major sources under the new definition.

- EPA also promulgated a NESHAP for oil and natural gas production facilities for area sources in 2007. As is true for the major source NESHAP, the oil and natural gas production facilities source category for area sources includes oil and gas well sites and other oil and gas facilities, such as pipeline gathering stations and natural gas processing plants. The 2007 area source rule addresses emissions from one emissions point, triethylene glycol dehydrators, which are used to remove water from gas. Area sources are required to notify EPA that they are subject to the rule, but EPA does not track whether the facilities providing notification are well sites or oil and natural gas facilities, so it is difficult to determine to what extent oil and gas well sites are subject to the area source NESHAP.[27]
- In addition to specific programs for regulating hazardous air pollutants, CAA establishes that operators of stationary sources that produce, process, or handle listed or extremely hazardous substances have a general duty to identify hazards that may result from releases and take steps needed to prevent releases. Methane is one of the hazardous substances identified in this part of CAA due to its flammable properties. Some EPA regional officials said that they use infrared video cameras to conduct inspections to identify leaks of methane from storage tanks or other equipment at well sites. For example, EPA region 6 officials said they have conducted 56 inspections since July 2010 and issued 10 administrative orders related to violations of CAA general duty clause.[28] EPA headquarters officials said that all well sites are required to comply with the general duty clause but that EPA prioritizes and selects sites for inspections based on risk.
- CAA also required EPA to publish regulations and guidance for chemical accident prevention at facilities using substances that pose the greatest risk of harm from accidental releases; the regulatory program is known as the risk management program. The extent to which a facility is subject to the risk management program depends on the regulated substances present at the facility and their quantities, among other things. EPA's list of regulated substances and their thresholds for the risk management program was initially established in 1994 and has been revised several times. The regulated chemicals present at

[27]In addition to NESHAPs specific to the oil and natural gas production industrial source category, EPA promulgated other NESHAPs that could apply to oil and gas well sites depending on the types of equipment in use and their size. See appendix IV for more details.

[28]EPA Region 6 includes the states of Arkansas, Louisiana, New Mexico, Oklahoma, and Texas.

oil and gas well sites include components of natural gas (such as butane, propane, methane, and ethane). However, a 1998 regulatory determination from EPA provided an exemption for naturally-occurring hydrocarbon mixtures (such as crude oil, natural gas, natural gas condensate, and produced water) prior to entry into a processing facility or refinery; EPA explained at the time that these chemicals do not warrant regulation and that the general duty clause would apply in certain risky situations.[29] Many of the regulated chemicals are thus exempt from the threshold determination of a facility subject to the risk management program. EPA officials said that unless other flammable substances, such as ammonia, were brought to the site, well sites would not trip the threshold quantities for the risk management regulations. In September 2011, the U.S. Chemical Safety and Hazard Investigation Board (Chemical Safety Board) released a report describing 26 incidents involving fatalities or serious injuries related to oil and gas storage tanks located at well sites between 1983 and 2010.[30] The report found that these accidents occurred when the victims—all young adults—gathered at rural unmanned oil and gas storage sites lacking fencing and warning signs, and the report concluded that such sites pose a public safety risk. The report also noted that exploration and production storage tanks are exempt from the risk management requirements of the Clean Air Act and recommended that EPA use the CAA general duty clause to encourage owners and operators to reduce these risks.[31] The Chemical Safety Board requested that EPA provide a response stating how EPA will address the recommendation within 180 days. EPA has yet to provide the response.

Stationary Sources – Greenhouse Gas Reporting

- As of 2012, oil and natural gas production companies are required to report estimates of their greenhouse gas emissions to EPA on an annual basis as described in EPA's greenhouse gas reporting rule. According to EPA documents, oil and gas well sites may emit greenhouse gases, including methane, carbon dioxide, and nitrous oxide, from several sources: (1) combustion sources, such as engines used on site, which typically burn natural gas or diesel fuel; and (2) process sources, such as leaks, venting, and fugitive emissions.[32] The greenhouse gas reporting rule requires oil and gas production facilities that emit more

[29]In addition, a 1999 law provided an exemption for flammable substances being used as fuel; this exemption applies to any type of facility using fuel. Pub. L. No. 106–40 § 2 (Aug. 5, 1999)
[30]The Chemical Safety Board is an independent federal agency investigating chemical accidents to protect workers, the public, and the environment. See U.S. Chemical Safety and Hazard Investigation Board, *Investigative Study Final Report: Public Safety at Oil and Gas Storage Facilities*, Report No. 2011-H-1 (September 2011).
[31]The Chemical Safety Board also noted that exploration and production storage tanks are exempt from the security requirements of the Clean Water Act's spill prevention program.
[32]Other major greenhouse gases include synthetic gases such as hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

than 25,000 metric tons of carbon dioxide equivalent to report their annual emissions of carbon dioxide, methane, and nitrous oxide from equipment leaks and venting, gas flaring, and stationary and portable combustion. When an operator owns or operates multiple wells in a single basin, EPA requires that the operator report the well data collectively for that basin. EPA documents estimate that approximately 467,000 wells are required to report under the rule.

Resource Conservation and Recovery Act

- RCRA, passed in 1976, established EPA's authority to regulate the generation, transportation, treatment, storage, and disposal of hazardous wastes.[33] Subsequently, the Solid Waste Disposal Act Amendments of 1980 created a separate process by which oil and gas production wastes originating within a well would not be treated as hazardous unless EPA conducted a study of wastes associated with oil and gas development and then determined that such oil and gas wastes warranted regulation as hazardous waste, followed by congressional approval of the regulations. EPA conducted the study and, in 1988, issued a determination that it was not warranted to regulate oil and gas exploration and production wastes as hazardous. Based on this EPA determination, exploration and production wastes that originate from within a well are not regulated as hazardous. According to EPA guidance issued in 2002, other wastes generated at well sites may be regulated as hazardous. For example, unused hydraulic fracturing fluids, painting wastes, and liquid and solid wastes generated by cleaning crude oil tank bottoms may all be present at well sites and could be regulated as hazardous, depending on the specific characteristics of the wastes. Facilities that generate more than 100 kilograms (220 pounds) of hazardous waste per month are regulated as generators and, among other things, are required to have an EPA identification number and to participate in the manifest system for tracking hazardous waste. Facilities generating smaller quantities of hazardous waste are not subject to these requirements.[34] EPA headquarters officials said they do not have data on how many well sites may be hazardous waste generators. EPA officials from three of the four regions we spoke with told us that they were unaware of any instances in which oil or gas well sites generated enough

[33]Pub. L. No. 94-580, 90 Stat. 2795 (1976) (amending the Solid Waste Disposal Act, but generally referred to as RCRA), codified as amended at 42 U.S.C. §§6901-6992k (2011). RCRA also created a framework in which states are responsible for solid (i.e., nonhazardous) waste regulations, including treatment and land disposal of these wastes. State solid waste provisions will be discussed in greater detail later in this report.

[34]These conditionally exempt small quantity generators are subject to limited generator waste management standards, namely to identify their hazardous waste, comply with storage limit requirements, and ensure waste treatment or disposal in a proper facility.

hazardous waste to become regulated and require an EPA identification number.[35] EPA officials said that states may have more information about quantities of hazardous wastes at well sites. As such, we asked state officials responsible for waste programs whether they were aware of well sites being classified as small-quantity hazardous waste generators and officials in all six states we reviewed indicated that they were unaware of well sites having sufficient quantities of hazardous wastes to be subject to those regulations.

- In September 2010, the Natural Resources Defense Council submitted a petition to EPA requesting that EPA regulate wastes associated with oil and gas exploration and production as hazardous. The petition asserts that EPA should revisit the 1988 determination not to regulate these wastes as hazardous because, among other things, EPA's underlying assumptions concerning the availability of alternative disposal practices, the adequacy of state regulations and the potential for economic harm to the oil industry are no longer valid. According to EPA officials, the agency is currently reviewing the information provided in the petition but does not have a timeframe for responding.
- RCRA also authorizes EPA to issue administrative clean up orders in cases where handling, treatment, or storage of hazardous or solid waste may present an imminent and substantial endangerment to health or the environment. EPA has used RCRA's imminent and substantial endangerment authorities related to oil and gas well sites. For example, EPA Region 8 issued RCRA imminent and substantial endangerment orders to an operator in Wyoming after discovering that pits near oil production sites were covered with oil and posed a hazard to birds. In response, the operator installed netting to prevent birds or wildlife from entering pits.

Comprehensive Environmental Response, Compensation, and Liability Act

- Congress passed CERCLA in 1980 to protect human health and the environment by addressing the cleanup of hazardous substance releases.[36] CERCLA established a system governing the reporting and cleanup of releases of hazardous substances and provides the federal government the authority to respond to actual and threatened releases of hazardous substances, pollutants, and contaminants that may endanger public health and the environment. CERCLA requires operators of oil and gas sites to report certain releases of hazardous substances and gives EPA authority to respond, but the Act excludes releases of petroleum (including crude oil and other petroleum products) from these provisions. As previously discussed, releases of petroleum products are covered by the CWA if the release

[35]In contrast, EPA Region 8 officials said they were unaware of instances in which well sites had asked EPA for an ID number.
[36]Pub. L. No. 96-510 (1980), codified, as amended, at 42 U.S.C. §§ 9601-9675 (2011).

threatens surface waters. EPA officials identified some instances of petroleum spills in dry areas that did not reach surface waters and explained that EPA had no role related to the investigation or clean-up of these incidents. Some states have cleanup programs that address contamination from oil as well as hazardous substances. For example, of the 6 states we reviewed, X states have authority to require cleanup of oil spills even if they do not reach surface waters.

- For hazardous substances, CERCLA has two key elements relevant for the unconventional oil and gas industry: release reporting and EPA's investigative and response authority. Similar to the requirements to report oil spills under the CWA, CERCLA requires companies to report releases of hazardous substances above reportable quantities to the National Response Center. The National Response Center shares information about spills with other agencies, including EPA regional offices, which allows EPA the opportunity to follow up on reported spills. EPA also has investigative and response authority under CERCLA, including provisions allowing EPA broad access to information and the authority to enter property to conduct an investigation or a removal of contaminated material. Specifically, EPA has the following authorities:
    - *Investigative*. EPA may conduct an investigation in response to an actual or threatened release of hazardous substances. These investigations can include activities such as monitoring, surveying, testing, and other information gathering. EPA officials described several instances in which the agency used CERCLA's investigative authorities relating to alleged hazardous substances releases from oil and gas well sites. For example, EPA is using CERCLA authority to investigate private well contamination potentially related to nearby oil and gas well sites in Dimock, Pennsylvania, and Pavillion, Wyoming.
    - *Response*. EPA has the authority to issue administrative orders requiring a company potentially responsible for a release to take response actions. For example, EPA issued an administrative order to a conventional well site operator in Alaska related to imminent and substantial endangerment of the environment. The incident occurred in the 1990s, and the company ultimately pled guilty to a criminal felony related to CERCLA violations after waste oil and hazardous substances were improperly disposed of over a 2-year period. In addition to the CERCLA violations, this case also involved violations of RCRA, SDWA, and EPCRA.

Environmental Planning and Community Right-to-Know Act

- Among other things, EPCRA provides individuals and their communities with access to information regarding storage or release of certain chemicals in their communities.[37] Two provisions of EPCRA – release notification and chemical storage reporting – apply to oil and gas well sites. The release notification provisions require companies that produce, use, or store certain chemicals to notify state and local emergency planning authorities of certain releases that would affect the community.[38] Spills that are strictly onsite would not have to be reported under EPCRA, but may still have to be reported to the National Response Center under provisions of the CWA or CERCLA. In addition, companies would have to comply with EPCRA's chemical storage reporting provisions, which require facilities storing or using hazardous or extremely hazardous chemicals over certain thresholds to submit an annual inventory report including detailed chemical information to state and local emergency planning authorities and the local fire department.[39] When asked whether oil and gas well sites would commonly trigger EPCRA's release notification and chemical storage reporting requirements, EPA officials said X.
- EPCRA also established the Toxics Release Inventory (TRI)—a publicly available database containing information about chemical releases from more than 20,000 industrial facilities—but EPA regulations for the TRI do not require oil and gas sites to make such reports. Specifically, these provisions of EPCRA generally require certain facilities that manufacture, process, or otherwise use any of more than 600 listed chemicals to report annually to EPA and their respective state on chemicals used above threshold quantities, the amounts released to the environment, and whether they were released into the air, water, or soil. EPCRA specified certain industries subject to the reporting requirement—which did not include oil and gas exploration and development—and also provided authority for EPA to add or delete industries going forward.[40] EPA issued regulations to implement the TRI in 1988 and chose not to change the list of industries subject to the provision at that time. In 1997, EPA promulgated a rule adding seven industry groups to the list of industries required

[37]Pub. L. No. 99-499, 100 Stat. 1728 (1986), codified at 42 U.S.C.§§ 11001 – 11050 (2011).
[38]Three types of releases must be reported: (1) release of extremely hazardous substances for which notification is also required under CERCLA § 103(c), (2) release of extremely hazardous substances for which notification is not required under CERCLA § 103(c), but above reporting thresholds and subject to additional conditions, and (3) release of other hazardous substances for which notification is also required under CERCLA § 103(c), subject to CERCLA reporting thresholds or one pound default threshold. EPCRA § 304(a), 42 U.S.C. §§ 11004(a) (2011).
[39]Specifically, the thresholds are (1) more than 500 pounds or the threshold planning quantity, whichever is lower, of extremely hazardous substances, or (2) more than 10,000 pounds of other hazardous chemicals.
[40]In addition to identifying industries, EPCRA specifies that reporting requirements apply to owners and operators of facilities: (1) with 10 or more full-time employees and (2) that manufactured, processed, or otherwise used a listed toxic chemical in excess of the reporting threshold during the calendar year.

to report releases to the TRI, including coal mining and electrical utilities that combust coal and/or oil.[41] In developing the 1997 rule, EPA considered including oil and gas exploration and production but did not do so because, according to EPA's *Federal Register* Notice for the final rule, there were concerns about how "facility" would be defined for this industry. At that time, EPA's stated rationale was that the oil and gas exploration and production industry is unique in that it may have related activities over a large geographic area and while together these activities may involved the management of chemicals regulated by the TRI program, taken at the smallest unit—an individual well—the chemical thresholds are unlikely to be met. According to EPA officials, EPA is in the pre-proposal stage of developing a new rule to add additional industrial sectors into the TRI program. Officials confirmed that they are considering including the oil and gas exploration and production industry as well as other industries.[42] EPA officials said there is not yet a timeline for this proposed rule.

Toxic Substances Control Act

- TSCA authorizes EPA to regulate, among other things, the manufacture, processing, and use of chemical substances.[43] TSCA provides EPA with the authorities to collect information about chemical substances or to require companies to develop information about risks and take action to protect against risks.[44] TSCA allows chemical companies to designate information provided to EPA as confidential to protect trade secrets; if the information provided meets certain criteria, EPA must protect it from disclosure to the public.
- EPA maintains a list of chemicals in commerce called the TSCA inventory. Of the over 82,000 chemicals currently in the TSCA inventory, about 62,000 were already in commerce when EPA began reviewing chemicals in 1979. Since then, EPA has reviewed more than 45,000 new chemicals, of which approximately 20,000 were added to the inventory after

[41]The complete list of industries added by EPA in 1997 includes metal mining, coal mining, electrical utilities that combust coal and/or oil for the purpose of generating power for distribution in commerce, refuse processing or destruction facilities regulated under RCRA's hazardous waste provisions, chemical wholesalers, petroleum terminals, and bulk stations and solvent recovery services.
[42]Specifically, officials said that EPA is also considering steam generation from coal and/or oil, petroleum bulk storage, iron ore mining, phosphate mining, large dry cleaning, and solid waste combustors and incinerators.
[43]Pub. L. No. 94-469, 90 Stat. 2003 (1976), codified as amended at 15 U.S.C.§§ 2601-2692 (2011). TSCA addresses those chemicals manufactured or imported into the United States, but it excludes certain substances, such as pesticides, which are regulated under the Federal Insecticide, Fungicide, and Rodenticide Act, and pharmaceuticals that are regulated under the Federal Food, Drug, and Cosmetics Act.
[44]These authorities are conditional on EPA making certain findings. For example, the act requires EPA to demonstrate certain health or environmental risks before it can require companies to further test their chemicals. TSCA provides EPA with differing authorities for managing risks, depending on whether the risks are posed by new or existing chemicals. For new chemicals, EPA can restrict a chemical's production or use if the agency determines that insufficient information exists to permit a reasoned evaluation of the health and environmental effects of the chemical and that, in the absence of such information, the chemical may present an unreasonable risk. For existing chemicals, EPA may regulate a chemical for which it finds a reasonable basis exists to conclude that it presents or will present an unreasonable risk.

chemical companies began manufacturing them. EPA officials are currently analyzing information provided by nine hydraulic fracturing service companies to determine which chemicals used in hydraulic fracturing are already on the TSCA inventory. EPA officials said that they expect most of these 900 chemicals are on the TSCA inventory but that the comparison is complex because EPA must examine duplicate chemical names and numerous mixtures. These officials said that they plan to complete their analysis on this issue by December 2012.

- In August 2011, EPA received a petition from the environmental group Earthjustice and others asking the agency to exercise TSCA authorities and issue rules to require manufacturers, and processors of chemicals used in oil and gas exploration and production to provide certain information to EPA.[45] According to the petition, EPA and the public currently lack adequate information about the health and environmental effects of chemicals used in oil and gas exploration and production and that EPA should exercise its TSCA authorities to ensure that chemicals used in oil and gas exploration and production do not present an unreasonable risk of harm to health and the environment. In a letter to the petitioners, EPA granted a part of the petition, stating there is value in beginning a rulemaking process under TSCA to obtain data on chemical substances used in hydraulic fracturing. EPA's letter also stated that the TSCA proposal would focus on providing an aggregate picture of the chemical substances used in hydraulic fracturing which would complement well-by-well disclosure programs in some states. According to EPA officials, the agency is drafting an advanced notice of proposed rulemaking on this issue that they hope to publish in [date]. Following this notice, EPA officials plan to initiate a stakeholder process to gather additional information for a proposed rule.

Federal Insecticide, Fungicide, and Rodenticide Act

- FIFRA, as amended, mandates that EPA regulate the use and sale of pesticides to protect human health and preserve the environment.[46] FIFRA requires that EPA register new pesticides, which is a very specific process that describes the chemical and its intended use and is supported by research data. According to EPA officials, some pesticides registered under FIFRA are used in hydraulic fracturing, and EPA has approved registrations of some pesticides for this purpose. According to a report by the Ground Water Protection Council

[45]Earthjustice et al, Letter to Lisa P. Jackson, EPA Administrator, re: Citizen Petition under Toxic Substances Control Act Regarding the Chemical Substances and Mixtures Used in Oil and Gas Exploration or Production, Aug. 4, 2011.
[46]The Federal Environmental Pesticide Control Act, Pub. L. No. 92-516, 86 Stat. 973 (1972) (amending FIFRA), codified as amended at 7 U.S.C. §§ 136-136y (2011).

about shale gas development,[47] operators may use pesticides to kill bacteria or other organisms that may interfere with the hydraulic fracturing process. For example, glutaraldehyde may be used by operators to eliminate bacteria that produce byproducts that cause corrosion inside the well and was reregistered for this purpose by EPA in 2007.

Exemptions Are Related to Preventive Programs

- In six of the eight federal environmental laws identified, there are exemptions or limitations in regulatory coverage related to the oil and gas exploration and production industry. These exemptions are related to programs designed to prevent pollution (see table 2). For example, under the CWA, EPA generally requires permits for stormwater discharges at construction sites, which prevents sediment from entering nearby streams. However, the Water Quality Act of 1987 exempted the oil and gas exploration and production sector from these stormwater permitting requirements. Four of the exemptions are statutory (related to SDWA, CWA, CAA, and CERCLA) while three were regulatory decisions made by EPA (related to CAA, RCRA, and EPCRA). States may have regulatory programs related to some of these exemptions or limitations in federal regulatory coverage. For example, although oil and gas production "downhole" wastes are not regulated under RCRA as hazardous, which reduces the federal role in management of such wastes, they are nonetheless solid wastes and subject to state regulation. See Appendix X (included below) for a more detailed comparison of federal, state, and federal lands requirements.

Table 2. Exemptions or Limitations in Regulatory Coverage for the Oil and Gas Exploration and Production Industry in Six Environmental Laws

Law	Description	Source	Type of program	
			Preventive	Response
SDWA	Hydraulic fracturing with fluids other than diesel fuel does not require an UIC permit.	Statutory (2005)	X	
CWA	Federal stormwater permits are not required for uncontaminated stormwater at oil and gas construction sites or at oil and gas well sites.	Statutory (1987)	X	
CAA	Oil and gas well sites may not be aggregated together or with other production facilities to determine whether they are a major source of hazardous air pollutants.	Statutory (1990)	X	
	In Risk Management Program, oil and gas are not counted towards threshold quantities of hazardous substances	Regulatory/EPA Decision (1988)	X	

[47] Ground Water Protection Council. "Modern Shale Gas Development in the United States: A Primer." Prepared for the Department of Energy and National Energy Technology Laboratory. April 2009.

RCRA	Waste from "downhole" is not hazardous waste.	Regulatory/EPA Decision (1988)	X	
CERCLA	Liability and reporting provisions do not apply to injections of fluids for production, enhanced recovery, or produced water.	Statutory (1980)	X	
EPCRA	Oil and gas well operations are not required to report releases of listed chemicals to the TRI.	Regulatory/EPA Decision (1997)	X	

Source: GAO.

EPA has a variety of response authorities available under environmental statutes. Table 3 lists EPA authorities that may be applicable when conditions or events at a well site present particular risk to the environment or human health. Whether an authority is available depends on requisite conditions being met in a given instance. EPA officials said that, in some instances, response authorities of multiple federal environmental laws could be used to address an emergency situation. In 2001, EPA and the Department of Justice developed a memo advocating that officials consider the specifics of a situation and use the most appropriate authority.[48]

Table 3. Key EPA Response Authorities

Law	Key Response Authorities	Situation to Which Authority May Apply
Imminent & substantial endangerment and general response authorities		
SDWA	Imminent & substantial endangerment (§ 1431)	Contaminant present in or likely to enter a public water system or an underground source of drinking water
CWA	Imminent & substantial endangerment (§ 504)	Source(s) of pollution, including discharge of pollutant to water
	Response authority; imminent & substantial threat (§ 311)	Actual or threatened discharge of oil or hazardous substances to surface waters
CAA[49]	Imminent & substantial endangerment (§ 112(r)(9))	Accidental release to the air of regulated substance
RCRA	Imminent & substantial endangerment (§ 7003)	Past or present handling, storage, treatment, transportation or disposal of any solid waste or hazardous waste
CERCLA	Response authority; imminent & substantial endangerment (§ 104(a))	Actual or threatened release of any hazardous substance or pollutant or contaminant (other than petroleum)
	Imminent & substantial endangerment (§ 106(a))	Actual or threatened release of a hazardous substance from a facility[50]

[48]See EPA, Memorandum, Use of CERCLA § 106 To Address Endangerments that May Also Be Addressed Under Other Environmental Statutes, App. A (2001).

[49] In addition, CAA section 303 provides EPA a general imminent and substantial endangerment authority to address emission of air pollutants, where conditions are met.

Access, information, and inspection authorities		
SDWA	Access to records and to inspect facilities; ability to require provision of information (§ 1445(a)-(b))	Persons and facilities subject to UIC program requirements
CWA	Access to records and to inspect facilities (§ 308(a))	Location of effluent source
CAA	Access to records; ability to require provision of information (§ 114(a))	Person who owns or operates any emission source
RCRA	Access to records and to inspect facilities (§ 3007)	Persons or facilities that have generated, stored, treated, transported, disposed of, or otherwise handled hazardous wastes[51]
CERCLA	Access to records and to inspect facilities; ability to require provision of information (§ 104(e))	Location of actual or threatened release of any hazardous substance or pollutant or contaminant (other than petroleum)

Source: GAO.

Note: The table lists selected EPA authorities that may be applicable when conditions or events at a well site present particular risk to the environment or human health. Whether a particular authority is applicable depends upon the facts of the situation meeting all prerequisite conditions. EPA has other authorities not listed in the table, such as the ability to require certain persons to provide information and the ability to sample emissions or effluent. EPA also has authorities by which it may enforce requirements and address violations of the programs it administers.

Objective 2: State Requirements

- Underground injection of produced water in Class II UIC wells is a common method of permanent disposal of produced water in five of the six states we reviewed.[52] Five out of the six states we reviewed have primary responsibility for regulating injection wells, whereas EPA implements the program in Pennsylvania. The five states in our review that have been granted primacy for their Class II UIC programs obtained it under the alternative provisions in which they demonstrate to EPA that their program is effective in preventing endangerment of underground sources of drinking water, in lieu of adopting all Class II UIC requirements in EPA regulations. All states have requirements for Class II UIC wells relating to casing and cementing, injection pressure, mechanical integrity testing, well plugging, and the monitoring and reporting of certain information, among other requirements.

[50] Generally, CERCLA section 104 authorizes EPA to take various actions to respond to a release, whereas section 106 authorizes EPA to require potentially responsible parties to do so.
[51] EPA interprets to include solid waste that EPA reasonably believes may pose a hazard when improperly managed.
[52] Pennsylvania has six currently active Class II UIC wells, and produced water generated in Pennsylvania is often recycled or shipped to other states such as Ohio for disposal. Until recently, there was little interest in developing new Class II UIC wells in Pennsylvania. EPA officials said that they have received Y permit applications for Class II wells in the last X years and expect continued interest in the future.

Sidebar: Underground Injection and Earthquakes
From March 2011 to XY 2012, twelve earthquakes ranging in magnitude from 2.1 – 4.0 occurred near Youngstown, Ohio. In March 2012, the Ohio Department of Natural Resources reported that injection of produced water into nearby Class II UIC wells was the most likely cause of the earthquakes. The Ohio Department of Natural Resources placed a moratorium on injection into five Youngstown area UIC wells, and is currently examining its Class II UIC well permitting process and developing a series of changes to help address seismic activity concerns.

The National Academy of Sciences released a study in 2012 which concluded that underground injection does pose some risk for induced seismicity, but very few events have been documented over the past several decades relative to the large number of disposal wells in operation. The study noted that the injected fluid volume, rate, pressure, and proximity to existing faults and fractures are factors that determine the probability to create a seismic event, but effective and economic tools are not currently available to accurately predict induced seismicity prior to injection. The study made research recommendations, proposed actions to address induced seismicity, and suggested that the agency that issues UIC well permits is the most appropriate agency to oversee decisions made with respect to induced seismic events.

- Some states, such as Colorado and Pennsylvania, also have commercial facilities, which treat produced water before discharging it to surface waters or to municipal treatment plants. In addition, Ohio and Pennsylvania have allowed some POTWs to accept produced water, but there have been some recent restrictions on these actions.[53] In 2010, Ohio's Environmental Protection Agency (OEPA) approved a permit modification that allowed a POTW in Warren, Ohio to accept 100,000 gallons per day of produced water with concentrations of less than 50,000 milligrams per liter of total dissolved solids, which was then diluted and discharged to surface waters.[54] However, the Director of OEPA subsequently issued a determination in 2011 that the permit had been unlawfully issued because Ohio law does not generally permit the disposal of produced water through a POTW.[55] In response, OEPA did not reauthorize the POTW to accept produced water when its NPDES permit came up for renewal in 2012 and, according to OEPA officials, intends to deny NPDES permits to other POTWs that have expressed interest in accepting produced water. In addition, in 2011, EPA regional officials became aware that some POTWs and a centralized wastewater treatment facility in Pennsylvania were accepting produced water

[53]As discussed earlier in this report, EPA sets pretreatment standards that apply when wastewater is sent to a facility—such as an industrial treatment facility or POTW—before being discharged to surface waters. To date EPA, has not set pretreatment standards specifically for produced water, though there is a general requirement that discharges to POTWs cannot cause the POTW to violate its own NPDES permit or cause the receiving stream to violate water quality standards.

[54]This produced water has significantly more total dissolved solids than drinking water, for which the federal standard is 500 milligrams per liter.

[55]Ohio law provides that, generally, produced water must be disposed of only by underground injection, by surface application, in association with enhanced recovery of oil or gas resources from a well, or by other methods approved by the Chief of the Division of Oil and Gas Resources Management for testing or implementing a new technology or method of disposal. Ohio Rev. Code Ann. § 1509.22(C)(1). According to OEPA officials, the permit did not involve an approved test or implementation of a new technology or method of disposal.

from operators drilling for natural gas in the Marcellus shale formation. EPA officials said they found that some of these POTWs were violating their NPDES permits, partly because some pollutants in wastewaters associated with shale gas development—most significantly, high levels of salt—are not treated by the technologies typically used at these facilities. EPA issued X administrative orders to POTWs and to the centralized treatment facility in Pennsylvania requiring, among other things, that the POTWs either stop accepting produced water or implement a monitoring program to ensure that continued acceptance of produced water did not result in additional NPDES permit violations. In addition, the state of Pennsylvania requested that POTWs stop accepting produced water from Marcellus shale gas wells and began revising the POTWs' NPDES permits. State officials later reported that POTWs were no longer accepting produced water from the Marcellus shale, but EPA regional officials said that, based on water quality test results, it is possible that some POTWs are still accepting produced water, perhaps from outside of the Marcellus shale.

- Officials in the six states we reviewed were not aware of any oil or gas sites that would be regulated as hazardous waste generators under RCRA. Exploration and production wastes that originate from within a well, such as produced water and drill cuttings, are not currently regulated as hazardous wastes under RCRA, but well sites could be considered hazardous waste generators if they store or produce hazardous waste, such as some discarded hydraulic fracturing chemicals, above certain thresholds. However, both state officials and EPA officials from the four EPA regional offices we spoke with indicated that they were unaware of any instances in which oil or gas well sites generated enough hazardous waste to exceed this threshold and require an EPA identification number. Pursuant to RCRA, regulation of waste that is not considered hazardous is a state responsibility.

Objective 3: Additional Requirements on Federal Lands

- FWS officials said they have been able to work with other federal agencies to use certain federal authorities to minimize or remediate damage to the environment. For example, FWS worked with EPA to respond to a spill of produced water into a stream on a National Wildlife Refuge in Louisiana in 2005, in violation of the CWA. EPA, the Coast Guard, and the Department of Justice worked together on the case and the operator ultimately paid $425,000 to the FWS for the two affected wildlife refuges.

Objective 4: Challenges

Conducting Inspection and Enforcement Activities

- Officials at EPA reported that conducting inspection and enforcement activities for oil and gas development from unconventional reservoirs is challenging due to limited information as well as the dispersed nature of the industry and the rapid pace of development. More specifically, according to EPA headquarters officials, enforcement efforts can be hindered by a lack of information in a number of areas. For example, in cases of alleged groundwater contamination, EPA would need to link changes in groundwater quality or quantity to oil and gas activities before taking enforcement actions. However, EPA officials said that there are often no baseline data on the quality or quantity of the groundwater prior to oil and gas development. These officials also said that linking groundwater contamination to a specific activity may be difficult even in cases where baseline data are available because of the variability and complexity of geological formations.
- In addition, EPA officials do not always have information on the types of activities taking place or equipment being used at oil and gas well sites, making it difficult to know where to conduct inspections related to SDWA, CWA, and CAA. For example, regarding SDWA, EPA headquarters officials said that EPA requires operators conducting hydraulic fracturing operations with diesel fuel to apply for a Class II UIC permit,[56] but it is difficult for EPA to assess operators' compliance because EPA does not know which operators are using diesel. Similarly, with respect to the CWA, EPA officials said it is difficult to assess operators' compliance with the SPCC program, which establishes spill prevention and response planning requirements in accordance with CWA, because EPA does not know the universe of operators with tanks subject to the SPCC rule. In addition, related to CAA, EPA headquarters officials said that it would be difficult for EPA to find oil and gas wells that are subject to but noncompliant with NESHAPs because EPA does not have information on the universe of oil and well sites with the equipment that are significant to air emissions, and according to EPA region 8 officials, these rules are "self-implementing" and EPA would only receive notice from a facility that identifies itself as subject to the rules.
- Several EPA offices also mentioned that the dispersed nature of the industry and the rapid pace of development make conducting inspections and enforcement activities difficult. For example, officials in EPA region 5 said that it is a challenge to locate the large number of new well sites across Ohio and to get inspectors out to these sites because EPA generally

[56]As discussed earlier in this report, in 2005, the Energy Policy Act added a provision to SDWA specifically exempting hydraulic fracturing from the UIC program, unless diesel fuel is used in the hydraulic fracturing process.

does not receive information about new wells or their location.[57] EPA headquarters officials also mentioned that many oil and gas production sites are not continuously staffed, so EPA needs to contact operators and ensure that someone will be present before visiting a site to conduct an inspection. Officials in EPA region 6 said that the dispersed nature of the industry, the high level of oil and gas development in the region, and the cost of travel have made it difficult to conduct enforcement activities in their region.

- EPA officials in headquarters said that SDWA is a difficult statute to enforce because of the variation across states. Specifically, SDWA authorizes EPA to approve, for states that elect to assume this responsibility, individual states' programs as alternatives to the federal UIC Class II regulatory program. As a result, EPA's enforcement actions have to be specific to each state's individual program, which increases the complexity for EPA. In addition, SDWA requires that EPA approve each state UIC program by regulation rather than through an administrative process, and many of the federal regulations for state UIC programs are out of date. EPA officials said that this has hindered enforcement efforts, and some cases have been abandoned because EPA can only enforce those aspects of state UIC regulations that have been approved by federal regulation. For example, XYZ.

Limited Legal Authorities

- EPA officials also reported that the scope of their legal authorities for regulating oil and gas development is a challenge. For example, EPA officials in headquarters and regional offices told us that the exclusion of exploration and production waste from hazardous waste regulations under RCRA significantly limits EPA's role in regulating these wastes. For example, if a hazardous waste permit was required, then EPA would obtain information on the location of well sites, how much hazardous waste is generated at each site, and how the waste is disposed of; however, operators are not required to obtain hazardous waste permits for oil and gas exploration and production wastes, limiting EPA's role. In addition, officials in region 6 said that if a concern was raised about these wastes, EPA would not be able to address it without a change in regulations. Similarly, as we described earlier in this report, officials in region 8 noted that EPA cannot use either its CERCLA or CWA emergency response authority to respond to spills of oil if there is no threat to surface waters. Officials in EPA region 8 said this has resulted in XYZ bad effects.[58]

[57]EPA Region 5 includes Indiana, Illinois, Michigan, Minnesota, Ohio, and Wisconsin.
[58]EPA Region 8 includes Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming.

Appendix Material: UIC Program in PA

Table: Selected Requirements for Class II Injection Wells in Pennsylvania (EPA Direct Implementation)

Item	Citation (40 CFR section)	Federal UIC Class II Requirement [59,60]
Requirements for Existing Wells	144.55(a), (b)(2)-(3); 146.7	Operator must identify the location of all known wells in the area of review which penetrate the injection zone (or for wells operating over the fracture pressure of the injection formation, all known wells in the area of review penetrating formations affected by the increase in pressure). For such wells which are improperly sealed, completed, or abandoned, the operator shall also submit a plan of actions necessary to prevent movement of fluid into underground sources of drinking water ("corrective action"); adequate corrective actions become permit conditions.
Casing/cementing	146.22(b)(1) 147.1955(b),(c)	Wells shall be cased and cemented to prevent movement of fluids into or between protected aquifers. [61] Surface casing shall be installed and cemented from the surface to at least 50 feet below the base of the lowermost protected aquifer, and for brine disposal wells, install long string casing and tubing extending to the injection zone and cement to a point 50 feet above the injection zone. Design shall consider the depth to injection zone, depth to the bottom of the aquifer and the estimated injection pressures.
Operating Requirements	146.23, see also144.51(e)	Injection pressure shall not exceed maximum calculated to prevent new or propagation of fractures in the confining zone, and shall not cause movement of injection or formation fluids into a protected aquifer.
Monitoring/Reporting Requirements	146.23(b)(1), (c) 144.54	Permits are to specify monitoring requirements, including: (1) Representative monitoring of the nature of injected fluids; (2) Observation of injection pressure, flow rate, and cumulative volume (at specified frequencies depending on type of well and activity), and (3) Recording of injection pressure, flow rate and cumulative volume at least monthly. Results are to be summarized in an annual report.

[59] Requirements shown generally apply to new wells. Existing Class II wells, and new wells built in existing fields, were generally authorized by rule for up to five years from the effective date of the initial program, subject to conditions and requirements such as submission of inventory information. In Pennsylvania, the effective date of the federal UIC program was June 25, 1984. Existing Class II enhanced recovery or hydrocarbon storage wells may be authorized by rule for the life of the well.

[60] See generally 40 C.F.R. §§147.1951-1955, 144.1(f), Pts. 144, 146 (2011).

[61] In this table, "protected aquifer" refers to underground sources of drinking water; however, EPA UIC regulations define underground sources of drinking water as a subset of aquifers, namely an aquifer or its portion: (a)(1) Which supplies any public water system; or (2) Which contains a sufficient quantity of ground water to supply a public water system; and (i) Currently supplies drinking water for human consumption; or (ii) Contains fewer than 10,000 mg/l total dissolved solids; and (b) Which is not an exempted aquifer. 40 C.F.R. § 144.3 (2011). EPA estimates there are approximately 1000-2000 exempted portions of aquifers.

Mechanical Integrity Testing	144.51(q), 146.23(b)(3), 146.8	Mechanical integrity to be established prior to initial injection and tested once every five years: (1) must demonstrate absence of leaks by either monitoring of annulus pressure or pressure test with liquid or gas; (2) must demonstrate no significant fluid movement by results of a temperature or noise log; or cementing records demonstrating the presence of adequate cement to prevent such migration.
Approval prior to operation	144.51(q)	Yes, unless alternative schedule approved by EPA.
Plugging	146.10; 144.32(e)(10), 144.51(p)	Operator must submit plugging plan consistent with requirements. Well shall be plugged with cement to not allow the movement of fluids either into or between protected aquifers; allowed methods include (i) the Balance method; (ii) the Dump Bailer method; (iii) the Two-Plug method; or (iv) an approved comparable alternative. Report required within 60 days of plugging, certifying compliance or providing updated plan.
Requirements related to faults or seismicity	146.22(a), 146.3, 146.6.	Wells must be sited to inject into a formation which is separated from any protected aquifer by a confining zone that is free of known open faults or fractures within the area of review, which is either calculated or a minimum area within 1/4 mile radius of the well.

Appendix X - Crosswalk between Selected Federal Environmental Requirements, State Requirements, and Requirements on Federal Lands

This table is intended to show representative areas of regulation, focused on substantive requirements specific to oil and gas wells. Other activities at oil and gas well sites may also be subject to federal or state regulation.

AREA OF REGULATION	Federal Environmental Requirements	State Requirements [62]	Additional Requirements for Federal Minerals
Siting and Site Preparation			
Comprehensive Environmental Assessment Prior to Drilling	Generally no[63]	0 of 6	Yes
Identification or Testing of Water Wells Prior to Drilling of Production Wells	No	1 of 6 [identification alone] 2 of 6 [identification and testing][64]	Yes – identification No - testing
Required Setbacks from Water Sources	No[65]	5 of 6	Yes
Erosion Control, Site Preparation, Surface Disturbance Minimization, and Stormwater Management	Effectively no	6 of 6 [any]	Yes
Drilling, Casing, and Cementing			
Requirements relating to cementing/casing plans	No[66]	6 of 6[67]	Yes
Prescribed placement of surface casing relative to groundwater zones		6 of 6	Yes
Prescribed cementation techniques for surface casing		6 of 6	No [performance standards]
Requirement for cement waiting period and/or integrity tests		6 of 6	Yes
Blowout preventer[68] requirements		5 of 6[69]	Yes

[62]This column includes information on state requirements as specified in law or regulation, but in some cases operators may be subject to additional requirements in order to obtain a permit to drill.

[63]Under the National Environmental Policy Act (NEPA), federal agencies must assess the effects of major federal actions—those they propose to carry out or to permit—that significantly affect the environment. Many EPA activities relevant here are exempt from NEPA's procedural requirements by statute or recognition by courts that EPA procedures or environmental reviews under enabling legislation are functionally equivalent to the NEPA process. See 63 Fed. Reg. 58045 (Oct. 28, 1998).

[64]Testing requirement applies only to certain wells—proposed CBM wells in CO and wells proposed for urbanized areas in OH. Pennsylvania does not require operators to identify or test nearby water wells, but incentivizes producers to do so by presuming that operators are liable for changes in well water quality after drilling.

[65]There are no federal requirements regarding setbacks, but under Section 404 of the Clean Water Act, a permit from the Army Corps of Engineers is required to fill waters of the United States, such as wetlands.

[66]Generally federal environmental laws do not have drilling, cementing, or casing requirements related to drilling production wells. However, if the well is to be hydraulically fractured with diesel fuel, EPA would regulate the well as a Class II well under the underground injection control program authorized by the SDWA, and be subject to cementing and casing requirements. See 40 C.F.R. §§ 144.52 and 146.22. To date, however, EPA and state officials are unaware of any wells that were regulated in this way.

[67]Colorado, North Dakota, Ohio, Pennsylvania, and Wyoming require cementing/casing plans. Texas requires cementing/casing plans if an operator proposes a method of freshwater protection other than those prescribed by state regulations.

[68]Blowout preventers are devices placed on wells to help maintain control over pressures in the well and prevent the well from spewing oil in the case of a blowout

[69]ND, TX, and WY require blowout preventers, and CO and PA require blowout preventers in certain circumstances.

Hydraulic Fracturing			
Prior Authorization/Notice/Inspection Requirements	No	3 of 6[70]	Not currently, but in BLM proposed rule
Requirements to Disclose Information on Fracturing Fluids	No	6 of 6	Not currently, but in BLM proposed rule
Pressure Monitoring, Testing, Limitations or Other Mechanical Integrity Requirements Specific to Hydraulic Fracturing	No	4 of 6	No
Well Plugging			
Requirements for Notification, Plugging Plan or Method, Witnessing, and Reporting	No[71]	6 of 6	Yes
Orphan well programs	No	6 of 6	No[72]
Site Reclamation			
Pit Closure Requirements	No	6 of 6	Yes
Backfilling, Regrading, Recontouring, and Compaction Alleviation Requirements	No	6 of 6	Yes
Revegetation Requirements	No	5 of 6[73]	Yes
Waste Management			
Options for waste disposal:			
Underground injection	Yes (SDWA)	6 states allow underground injection and 5 have related requirements[74]	As part of the permit application, operators must describe the methods and locations for temporary storage of waste (such as in pits) as well as the final disposal of waste materials, including drill cuttings and produced water.
Discharge to Surface Water	Yes (CWA)	3 westerns states specifically allow surface discharges and have related regulatory requirements	
Requirements for POTWs or Centralized Waste Treatment Facilities	Pretreatment standards for shale gas wastewater under development (CWA)	Disposal at POTWs is an option in one state[75] Disposal at CWT facilities is an option in 3 states.	
Recycling or beneficial use	Yes (CWA)	6 states allow recycling or beneficial use and have related requirements	
Solid waste disposal	No[76]	All 6 states require solid waste taken off site, such as trash and drill	

[70]CO, OH, and WY all have a prior notice requirement. OH and WY require plans for well stimulation to be included in an application for permit to drill, which must be approved by the state before any drilling activity commences.
[71]Generally federal environmental laws do not have requirements related to well plugging. However, if the well is to be hydraulically fractured with diesel fuel, EPA would regulate the well as a Class II well under the underground injection control program authorized by the SDWA, and be subject to cementing and casing requirements. See 40 C.F.R. §§ 144.52 and 146.22.
[72]According to BLM officials we spoke with there is no formal program to plug orphan wells on federal lands, however BLM has plugged some orphan wells that were causing or had the potential to cause environmental problems.
[73]Colorado, North Dakota, Ohio, Pennsylvania, and Wyoming have revegetation requirements.
[74]Pennsylvania has no related requirements because EPA directly implements the UIC program in that state.
[75]Discharges may be authorized from a POTW in Pennsylvania if preceded by treatment at a CWT. Ohio has allowed a POTW to accept produced water in the past, but officials said they do not intend to approve such permits in the future.
[76]RCRA subtitle D prohibits open dumping of solid wastes.

		cuttings, to be disposed of in accordance with state solid waste rules.	
Hazardous waste disposal	Effectively no[77]	0 of 6 states treats exploration and production waste as hazardous waste.	
Pit Siting Requirements (with regard to sensitive areas)	No[78]	6 of 6	
Pit Lining Requirements	No	5 of 6[79]	
Freeboard[80] and Secondary Containment Requirements for Pits	No	6 of 6	TBD
Managing Air Emissions			
Requirements under the Clean Air Act for Criteria Pollutants	Certain provisions apply	5 of 6 states have permitting or registration programs under the State Implementation Plan[81]	
Requirements under the Clean Air Act for Hazardous Air Pollutants	Certain provisions apply	TBD	
Requirements Related to Hydrogen Sulfide Gas (H_2S)	No[82]	6 of 6	Yes
Requirements Related to Venting and Flaring	Venting – No Flaring – Under new NSPS regulation, hydraulically fractured gas wells will have to do green completions	6 of 6	Yes

[77]Per EPA's 1979 regulatory determination, wastes from "downhole" are not hazardous. Small amounts of hazardous waste may be at well sites (such as unused hydraulic fracturing fluids) but we could not identify any instances where these wastes were available in high enough quantities to trigger RCRA requirements.
[78]Under Section 404 of the Clean Water Act, a permit from the Army Corps of Engineers is required to fill waters of the United States, such as wetlands.
[79]Colorado, North Dakota, Pennsylvania, Texas, and Wyoming have specific pit lining requirements. Ohio regulations require pits to be "liquid tight."
[80]Freeboard is the height that is above the recorded highwater mark of a structure associated with a body of water and that is an allowance against overtopping by waves or other transient disturbances.
[81]In addition, Pennsylvania is in the process of revising its permit program to include oil and gas development.
[82]Although there are no specific requirements, owners and operators are subject to the Clean Air Act general duty clause to take steps to prevent accidental releases of listed and other substances to the air; these include hydrogen sulfide.

Complete List of Appendices